



# REMOTE CORROSION MONITORING OF OFF-SHORE PIPELINES

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**PROJECT SUMMARY**

**Title of Project:**

**REMOTE CORROSION MONITORING OF OFF-SHORE PIPELINES**

**Technical Abstract:**

Remote monitoring of internal corrosion in off-shore pipelines is technically feasible. This report provides the basis on which a system can be developed. Such monitoring is necessary because it will allow pipeline companies to ACT to control corrosion taking place in an increasingly severe internal environment, NOT REACT to an emergency situation when a pipeline rupture has taken place and there has occurred an oil "spill" in coastal waters.

Because of the large amount of information which would be necessary in order to properly monitor off-shore pipelines, it was determined that a computerized Data Base should be established. Data would be acquired, verified, logged in, and initially screened under software control using known statistical methods. By the establishment of such a data base a large amount of data could be utilized for day to day active corrosion control, detailed historical data on a ruptured pipeline, and hard research data. Because of the alarm feature, the system would be able to report the "exception condition". This happens when, due to a system upset, a severe corrosive condition exist. This feature will allow the pipeline operators to know that a system upset is taking place and take the appropriate action.

## Executive Summary

The goal of this project is to provide a means of remote monitoring the corrosion taking place in sub-sea pipelines. This will require remote corrosion monitoring from unmanned off-shore gathering platforms. This is the only location where the pipelines are accessible.

During our work on this project, we have found very few published facts are available on internal pipeline corrosion as it pertains to the off-shore pipeline industry. The engineering community recognizes internal corrosion as a major problem in such pipelines. A Data Base is needed.

The monitoring of internal corrosion taking place in off-shore pipelines will allow one to ACT to control internal pipeline corrosion rather than REACT to a pipeline rupture.

Three major benefits can be derived from remote monitoring of internal corrosion in off-shore pipelines and the Data Base generated.

- I. Day-to-Day Active Corrosion Control
- II. Detailed Historical Data On A Ruptured Pipeline
- III. Hard Research Data

In order to attain these benefits, one must recognize the large volume of information to be collected, and the strict need for a high degree of data integrity.

The only solution is the establishment of a computerized Data Base. To insure the integrity of the information, the data should be gathered, verified, and logged in under software control.

During Phase I, we have determined that a remote system for data acquisition from off-shore platforms is possible. We have also been able to determine that a statistical evaluation of the data is needed and is possible. Such a statistical evaluation would allow one to determine if a real change was taking place in the system.

To be able to determine the parameters capable of defining the system, a review of the known mechanisms which effect sub-sea pipelines was undertaken. From this information, and the limitations necessary to provide remote, reliable data acquisition, it was determined that three parameters are essential, and a fourth is highly desirable.

The three variables which are essential in defining the system are:

I. Corrosion Rate

II. Temperature

III. Pressure

The injection of chemicals is the only means of modifying a changing pipeline environment and its resultant effect on the internal corrosion rate. Therefore, an additional parameter necessary to monitor is film thickness. This would represent a direct measure of the degree of protection which is being provided by the chemical additive.

As the nation's off-shore pipeline system grows older, the net effects of internal corrosion failure will become more acute. It must be noted that corrosion control comes within the context of maintenance. While company policy may require that all facilities be properly maintained, for it does represent a major capital investment, it is generally recognized that a reduction in maintenance can give a short term bottom line major reduction in cost. Since internal pipeline corrosion does not initially cause catastrophic failure, in most cases, the results of reduced corrosion protection are not evident except in the savings incurred.

Only by the active use of a means of monitoring internal corrosion in off-shore pipeline systems can the hidden effects of poor pipeline maintenance be detected and eliminated. When the pipeline is new the engineers include a "corrosion factor" to compensate for the effects of internal corrosion. As the pipeline grows older this safety factor is depleted. If the potential of ecological damage did not exist, there would be little consequence to the rupture of a pipeline due to internal corrosion. However, the risk does exist. Therefore, it is the responsibility of industry, government, and private individuals to insure that this risk is held to an absolute minimum. Action should only be taken on the basis of facts. Facts can only be determined by measurement.

Therefore, it is our conclusion that a means of measuring internal corrosion in sub-sea pipelines is technically feasible and therefore essential.

## Section I

### INTRODUCTION

This project was initiated to determine the feasibility of remotely monitoring the corrosive effects of hydrocarbon streams in sub-sea pipeline systems. The benefit to be derived from this project is to allow responsible parties to ACT to prevent corrosion from breaching sub-sea pipelines causing an environmental problem, not REACT to an emergency situation when a pipeline rupture has taken place and there has occurred an oil "spill" in coastal waters.

As the nation's off-shore pipeline system grows older, the net effect of internal corrosion failure will become more acute. With the growth of the electronics industry, remote data transmission devices are becoming available. Because of current corrosion data gathering techniques, current corrosion data is not available to pipeline corrosion specialist while in their laboratory or at corporate headquarters. With the advent of small computers and remote transmission devices, it is currently possible to remotely monitor internal pipeline corrosion taking place in underwater pipelines....not after it has taken place, but while it is increasing in severity. This will allow corrective action to be taken.

The general objective of Phase I was to provide the necessary research which would allow us to determine if remote monitoring of the corrosion rate taking place in off-shore pipelines can be determined.

In order to accomplish this task, four specific Phase I objectives were addressed:

1. To determine if radio modems are available which would be able to transmit stored corrosion data from remote, off-shore platforms.
2. If remote radio modems are commercially unavailable which could be modified to transmit stored corrosion data from remote, off-shore platforms; to determine the electronic configuration necessary to accomplish this task.
3. To survey means of storing corrosion data so that remote transmission of the data is feasible.
4. To determine the feasibility of interconnecting corrosion monitoring devices so that remote acquisition of corrosion data is possible.

## BACKGROUND

Offshore pipelines are inadequately protected against internal corrosion. This condition exist, not because internal pipeline corrosion can not be controlled by the injection of chemical corrosion inhibitors into sub-sea pipelines, but as a direct result of inadequate off-shore pipeline corrosion monitoring. Why are off-shore pipeline stations inadequately monitored for internal pipeline corrosion? It is not because they do not represent a major capitol investment to the pipeline owners. It is not because the pipeline owners are irresponsible. The reasons are: (1) the remoteness of the off-shore platforms, (2) the lack of qualified personnel on location, (3) low cost to perceived benefit ratio from current instrumentation, and (4) the inability to respond to an increasingly corrosive environment.

The protection of a pipeline from corrosion can only be classified as maintenance. Good maintenance is necessary to prevent problems from occurring. If good corrosion protection is maintained on a pipeline, nothing happens. It cost a great deal of money and there is no decernable effects. What would have happened is not readily apparent. It is also an area where apparent savings can be made with no or little decernable effect. For this reason, many times the quality of corrosion protection in sub-sea pipelines is not as good as it could and should be.

If properly monitored, what condition could be corrected?

(a) Because of current restrictions regarding discharge of acids or acid/oil mixtures into coastal waters, when an off-shore oil well is being stimulated (acidized) to increase production, some operators or their agents will feed this low pH (acid) solution into the pipeline system. While this practice is expressly prohibited by the pipeline companies, this condition does exist.

While this acid water may be compensated for by an increased injection rate of chemical corrosion inhibitors, without proper corrosion monitoring, this condition will result in an extremely high rate of internal corrosion.

(b) If the feed rate is not properly calculated, the chemical corrosion inhibitor tanks on off-shore platforms can be pumped dry. When this occurs, time may pass during which the off-shore pipeline system is not being protected by chemical corrosion inhibitors. The net result is a high rate of internal pipeline corrosion.

(c) Offshore pipelines have been left unprotected due to:

- o Power to the injection pump is inadvertently shut off.
- o Power to the injection pump is not turned on.
- o A valve to the chemical corrosion inhibitor feed tank is shut off.
- o The theft of an injection pump.
- o The "borrowing" of an inhibitor injection pump to replace a failed pump on the rig.

All of these factors contribute to a high rate of internal corrosion which can be identified and can be corrected by proper monitoring of internal corrosion.

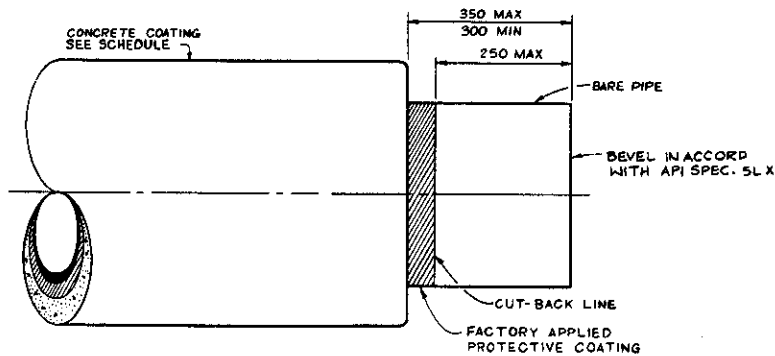
#### SUMMARY AND OVERVIEW OF THE NATURE OF THIS PROJECT

For many years, pipelines made of various grades of API carbon steel have been widely used in the transmission of oil and gas. There has been a considerable amount of research done to study the characteristics of the corrosion damage to underground pipelines, but little has been done to define and control the factors which affect the rate of corrosion of the offshore pipelines. Since the internal corrosion of sub-sea pipelines is the hardest area, in the field of corrosion inhibition, to control because of an absence of hard data. To address the problem of obtaining hard data, this project was undertaken.

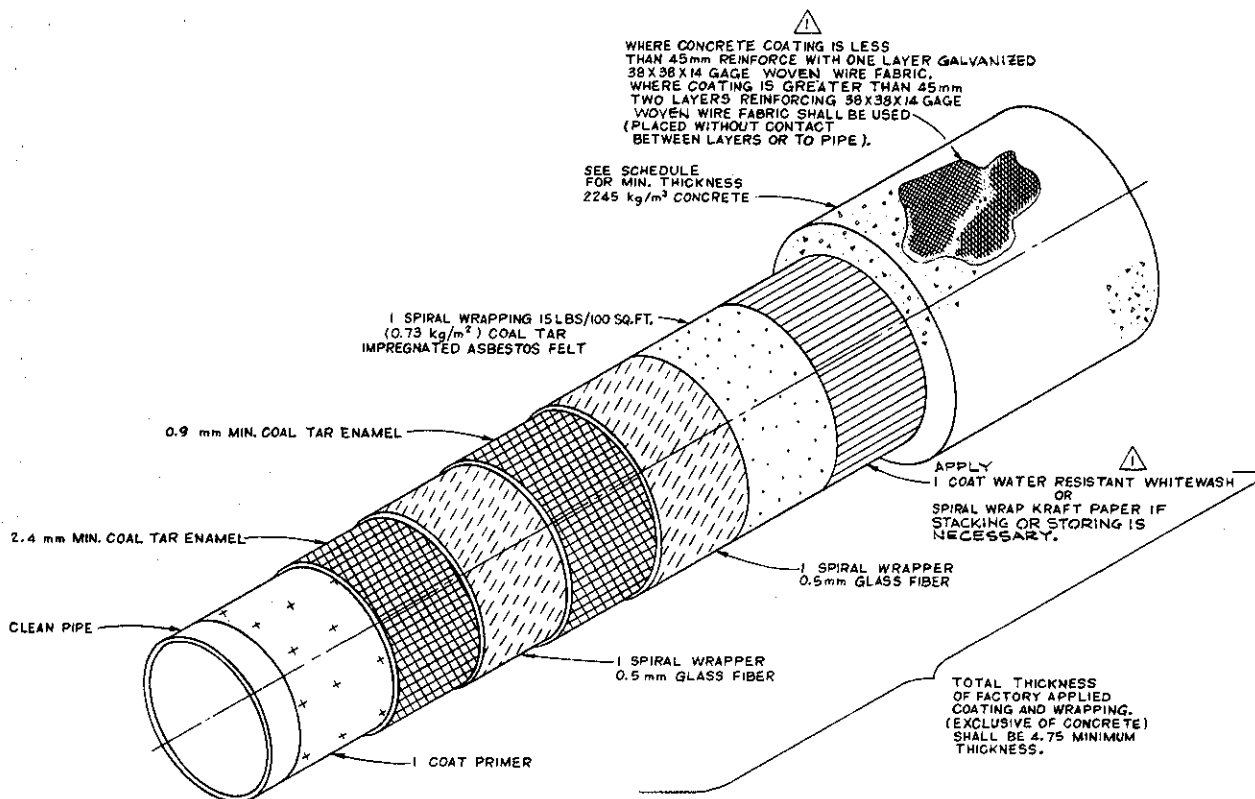
Before we undertake a detailed review of the corrosion mechanism which comes into play in sub-sea internal pipeline corrosion, let us mention several areas.

#### WHAT IS A SUB-SEA PIPELINE?

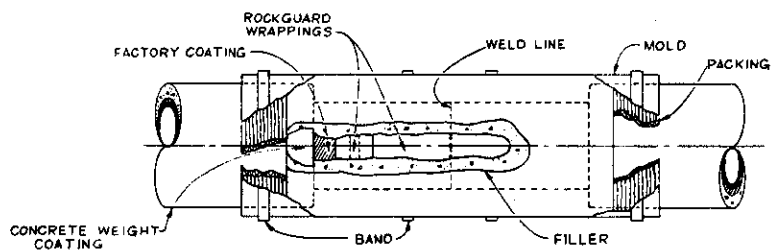
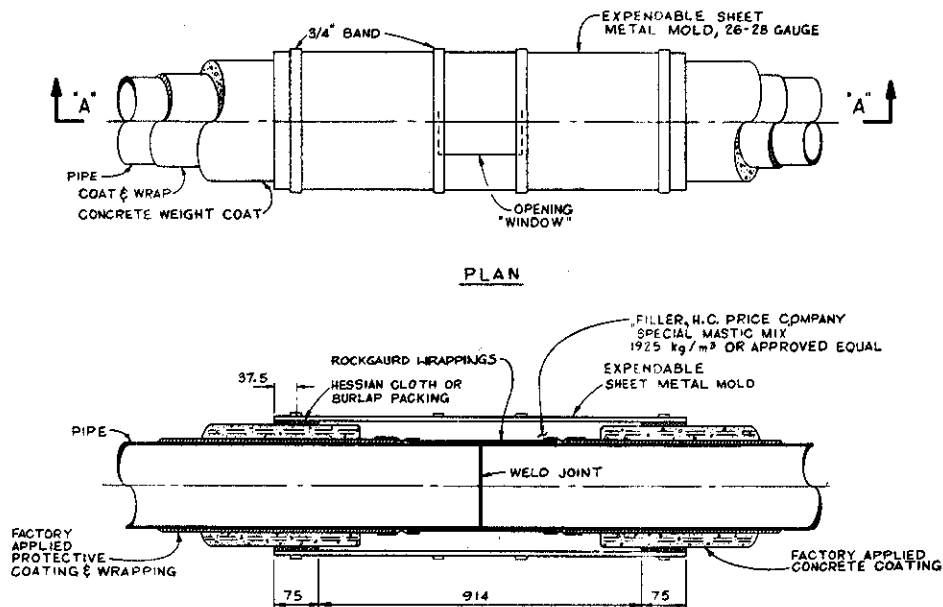
Initially, a off-shore pipeline was a pipe, made of carbon steel which was placed on the continental shelf to transport oil and gas from a off-shore well to land. Little effort was made to insure that it was buried in the sand. There was a little problem because the pipe, in some cases, had nearly a positive buoyancy. This led to the need to weight the pipe down with concrete weights. Current technology provides for a complete covering of the pipe with concrete. This can be seen in the following diagrams.



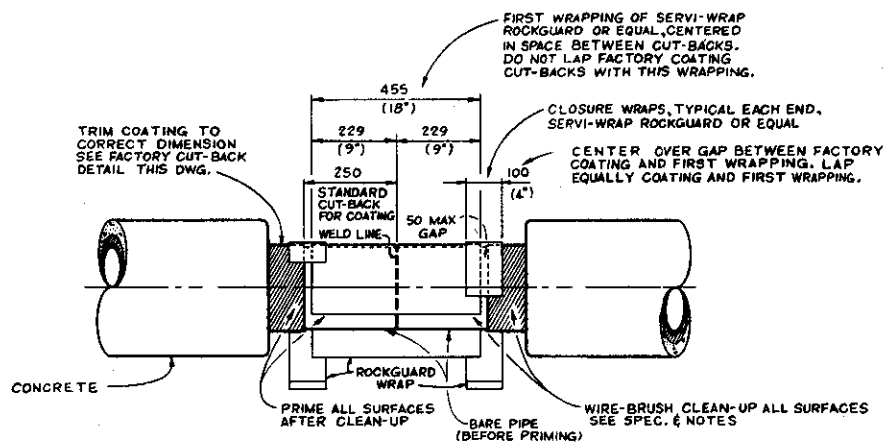
### TYPICAL CUT-BACKS FACTORY COATINGS SUBMARINE LINE PIPE AND RISER PIPE



### TYPICAL CONCRETE COATED SUBMARINE LINE PIPE AND RISER PIPE



**CUT AWAY ELEVATION**  
**TYPICAL COATING PLACEMENT**  
**SUBMARINE PIPE LINE AND RISER FIELD JOINT**



**TYPICAL WRAP FOR**  
**SUBMARINE PIPE LINE AND RISER FIELD JOINT**

## WHAT ARE THE ECONOMIC IN THE USE OF SUB-SEA PIPELINES?

Because of the large amount of oil and gas to be transported from off-shore locations, no other method of transport provides the unit cost advantage as does the sub-sea pipeline. When amortized over its lifetime it is less expensive than any other means of transportation. Even considering the high cost of laying the pipeline including lay barge, pipe, manpower, and ocean going stabilizing tugs, the price is still cheap when compared with any other means of transport.

## WHAT ARE ENVIRONMENTAL CONSIDERATIONS?

Few transportation systems have a greater potential for environmental catastrophe as does the sub-sea pipeline. This condition is present due to (1) the great amount of hydrocarbon in the system at any one time, and (2) man's inability to control it once the constraints upon the material are broken. We are also unable to contain the oil which escaped from the broken pipeline once this material is in the ocean. This is largely due to ocean currents and wave action. Also, while we are able to block any new material from entering the pipeline, any rupture in the line will allow that material which is present in the line to continue to escape. Therefore, we (individuals, industry, and government) have an enhanced responsibility to insure that hydrocarbons do not escape from the sub-sea pipeline transportation system because of negligence, inept maintenance of the pipeline system, or carelessness.

## Section II

### CORROSION

The nature of internal pipeline corrosion attack has generally been delineated in the industry as general corrosion, pitting corrosion, crevice corrosion, galvanic corrosion, and stress corrosion.

The cause of corrosion can be directly attributed to the impurities found in the produced oil and gas as well as the materials which are co-produced with them. These "bad actors" include (a) Carbon dioxide, (b) Carbon Monoxide, (c) Hydrogen Sulfide, (d) Oxygen, (e) Brine [salt water], (f) Organic Acids, (g) Inorganic Acids, and (g) Assorted Sulfur Compounds. Because of the non-specificity of the materials produced from a production well, some or all of these materials may be active in the generation of a corrosive environment inside the gathering pipeline.

For the engineers who have the responsibility of maintaining the integrity of the pipeline, there are four means of mitigating the effects of corrosion. They are:

1. Internal Coatings
2. Metallurgy
3. Pigging the Line
4. Chemical Corrosion Inhibitors

#### Internal Coatings

Coatings have been used to protect the pipeline where there is a large amount of high pressure gas and gas condensate. It has been proven that coatings can do a good job in the initial protection of the pipeline. However, later in the production life, iron count data shows little difference between those lines that have been coated and those that have not. It should be noted that the initial period in a production well's life can be its most corrosive time due to the partial pressure of Carbon Dioxide. Therefore it may be economical to protect the gathering pipelines from a young field. Two drawbacks should be noted. First, in coating a pipeline, it is necessary for the pipe to be coated prior to installation, and second, coating can not be relied on as the only means of corrosion control.....corrosion inhibitors and pigging the line is also imperative.

#### Metallurgy

As previously noted, the use of API grades of carbon steels in sub-sea pipelines has been somewhat satisfactory. Because of the high cost factor, stainless steels and superalloys can not be considered even though they do possess superior corrosion resistance over carbon steel in some applications. Today, there exist the possibility of using low-alloy steels for improved corrosion resistance. The result of recent research of Sumitomo

Metal Industry, Ltd. in Japan on the use of 0.25% Copper and 1.25% Chromium low alloy steel for oil pipelines is very promising. Not only can this new steel, designated CRLA, be as easily formed and welded as carbon steel in field conditions, but it can also provide a superior corrosion resistance, as much as three times higher than carbon steel, in laboratory test. These test were conducted using solutions of organic acid, hydrochloric acid and sulfuric acid.

Metallurgy also has a function in specific locations of a pipeline where conditions make specific pipe characteristics necessary. A prime example is the L joint at the bottom of a riser. In this particular location, there is an abrupt change of direction as the water, oil and gas are pumped from the top of a off-shore platform to a pipeline which extends along the ocean floor. Since most production oil and gas contain abrasive materials an erosion condition exist. This requires that the wall inside the pipe be coated (overlayed) with a material which is extremely abrasion resistant. Such materials as stellite serve this function.

As with coatings, it is necessary to provide for a metallurgical solution to the problem of internal pipeline corrosion prior to the construction of the pipeline or during pipeline retrofit. Thus it does not lend itself to changing corrosive environments.

#### Pigging the Line

Pigging refers to a mechanical device which is passed through the pipeline to physically remove water, sludge, and corrosion products which are present in the line. Due to the presence of physically low spots in the pipeline, it is necessary to good pipeline maintenance and corrosion control that a pig be run through the line every six (6) months.

A pipeline pig is a device which can be used to clean out the pipeline. It may also be used to purge the pipeline of its contents. A pipeline pig is generally made of a synthetic material such as fiberglass or synthetic rubber. It had approximately the same diameter as the interior diameter of the pipe less a fraction of an inch. Initially it was used to purge the line of any materials present. More recently it has been fitted with electronic instrumentation for doing Quality Control work on the pipeline. This will be discussed later in this report.

A pipeline pig has the advantage that only the pig launcher and pig receiver must be installed in the pipeline during the building of the pipeline. In fact some pig launchers are removable in that they need not remain in place. They only need to be connected to the pipeline when a pipeline pig is to be placed in the line.

Because of the ability of the pipeline pig to remove both corrosion products and sludge from the line, it has been found to be a positive factor in the corrosion control of the off-shore pipeline.

#### Chemical Corrosion Inhibitors

Sub-sea gathering pipelines contain anything from all gas and gas condensates to oil mixtures which contain as much as 30% water. Chemical corrosion inhibitors are chemicals which when added to a water/oil, water/gas, oil/gas, or water/oil/gas mixture in concentrations in the approximately 2 to 24 ppm (parts per million) concentration range establishes a barrier layer between the pipeline contents and the interior wall of the pipe. The major advantage which chemical corrosion inhibitors exhibit is that as the corrosive environment inside the pipeline increases, the corrosion rate can be decreased by the use of increased amounts of corrosion inhibitors. A second advantage is that the cause of the increasingly corrosive environment inside the sub-sea pipeline need not be attributed to any one of the causes of corrosion which we previously mentioned.....that is if the corrosion inhibitor which is to be used is carefully selected. Of course there are some inhibitors which are more effective when the reason of the increased corrosive environment is known. However, this knowledge is not imperative in order for them to be effective.

Because of the ability of chemicals to be added to a pipeline to reflect the corrosive environment, this allows for remedial action to be taken while the pipeline is in operation. As was noted in the case of Coatings to provide the barrier to corrosive attack, the Coating must be applied during fabrication of the pipeline. In the case of Metallurgy, this too must be installed with the pipeline. Pigging of the line is a remedy, to decrease the corrosive environment found in sections of the pipeline but it is not capable of being used on short notice. Chemical Corrosion Inhibitors are able to respond to an increase in the corrosive environment in the pipeline to reduce its effects.

#### CORROSION MONITORING

Because the injection of increased amounts of Chemical Corrosion Inhibitor is able to decrease the effects of a corrosive environment within the sub-sea pipeline, this provides the pipeline operator with a tool to provide increased levels of protection for his pipeline. In order to react to an increase in the corrosion rate, one must be cognizant that a change is taking place. Corrosion coupons, ultrasonic test, and pipe X-Ray films are ways of determining the condition of a pipeline. However, they can not be used in a sub-sea environment. In any case, these methods do not provide feed-back information, but generally are used in intensive investigations or in the case of corrosion coupons, over a period of time to obtain gross effects.

AMF Tuboscope in Houston, Texas and Rockwell International in Thousand Oaks, California have been doing a tremendous amount of research in building an ultrasonic corrosion-monitoring apparatus that can travel deeply into a pipeline to collect corrosion information. The Tuboscope Lin-A-Log system was used by various pipeline companies during an American Gas Association NG-18 project to study the extent of stress corrosion on the outside surface of pipe. Perhaps a similar device can be built to collect information on the internal corrosion of a pipeline.

However, these devices are not configured as to provide continuous information as to the state of the pipeline. Of more interest are probes which provide direct feed-back which can be used to react in controlling the pipeline corrosion rate.

For this reason, the use of direct read-out probes located on a gathering platform, at the juncture of several feeding pipelines, seems to be the proper location for the monitoring unit. This will allow several of the pipelines which feed into the gathering platform to be monitored as well as the main pipeline which goes to shore.

### Section III

#### CORROSION MECHANISM

There is no clear understanding of the precise mechanism which is present in any form of corrosion. The process of corrosion, which is taking place under almost any condition, will consist of multiple processes. Each with their separate mechanism. In some cases, the corrosion process will actually work to prevent corrosion at a particular location. An example of this is when a brass material is used in conjunction with carbon steel. The brass is cathodic with respect to the carbon steel. Thus as long as this condition exists the brass is protected and the corrosion rate of the carbon steel is enhanced.

The following is an evaluation of the types of corrosion which may be encountered in off-shore pipelines.

#### CORROSION TYPES

There are eight known basic forms of corrosion. They are (1) uniform or general attack, (2) galvanic corrosion, (3) crevice corrosion, (4) pitting, (5) intergranular corrosion, (6) selective leaching, (7) erosion corrosion, and (8) stress corrosion.

##### Uniform Attack

This is the most common form of corrosion. It is usually characterized by a chemical or electrochemical reaction which proceeds uniformly over the entire exposed surface or over a large area. The metal becomes thinner and then fails. An example would be that of placing a piece of carbon steel in a dilute acid solution. In such a hydrochloric or sulfuric acid solution the metal dissolves at a uniform rate over the entire surface.

This kind of corrosion represents the greatest destruction of metal on a tonnage basis. However, it also represents the most harmless type of corrosion. As long as uniform attack takes place the corrosion rate can be calculated and corrective action can be taken. This may mean replacing a section of pipe.

##### Galvanic Corrosion

In this type of corrosion, three elements must be present. A potential difference between two locations, an electrical connection so that electrons may flow, and an conductive solution (electrolyte), so that ionic charges may move through the solution. This type of attack is limited by transport mechanisms, micro-surface characteristics, surface capacitance, and other environmental factors. The two conditions which most often promote this condition is when either the concentration of corrosive elements are greater at one location than at a second location (a concentration cell), or the metal at one location is

of a different composition than at a second location (the two metal effect).

### Crevice Corrosion

This may be considered to be a form of galvanic corrosion. In this case the concentration of the electrolyte in the crevice is different from the bulk environment, thus a concentration cell may be formed. The cause of the electrolyte being different in the crevice may be due to oxygen partial pressure, corrosion products, depletion of material due to the corrosion process or other factors. While this may not be a completely different mechanism by which corrosion takes place, because it is commonly considered as such because of it being very prevalent under process and pipeline conditions.

### Pitting Corrosion

This too is a form of galvanic corrosion. However, like crevice corrosion, since it is often found under operational conditions, it is considered a separate type of corrosion. Pitting corrosion is characterized by a small area (general oval or round) where a large amount of metal has been removed by the corrosion process. Because of its distinctive shape, and the serious nature of this type of corrosion, it is well known. It should be noted that in both crevice corrosion and pitting corrosion, metal is displaced from a very limited area and the metal loss is small; however, because of these factors the entire wall thickness of a pipe may be penetrated or a weak spot in the pipe will be generated. In cases where the pipe is under pressure, a large rupture may occur.

### Erosion Corrosion

This type of corrosion is defined as the acceleration or increase in rate of deterioration or attack on a metal because of relative movement between a corrosive fluid and the metal surface. The movement is generally quite fast, and mechanical wear effects or abrasion are involved. Various studies indicate that the zeta potential may be a factor in the loss of metal where rapid movement is present; however, more work is needed to define the overlap. In most cases, metal is removed from the surface as dissolved ions, or it forms solid corrosion products which are mechanically swept from the metal surface.

This type of corrosion is characterized in appearance by grooves, gullies, waves, rounded holes, and valleys and usually shows a directional pattern.

The two photographs on the following page show graphically this condition. These photographs are actual records of corrosion which took place in a pipeline which carried a multiphase fluid. The attack took place at the 6 o'clock position and represented a combination of fluids which included: oil, light hydrocarbons, and water.



Photo 1

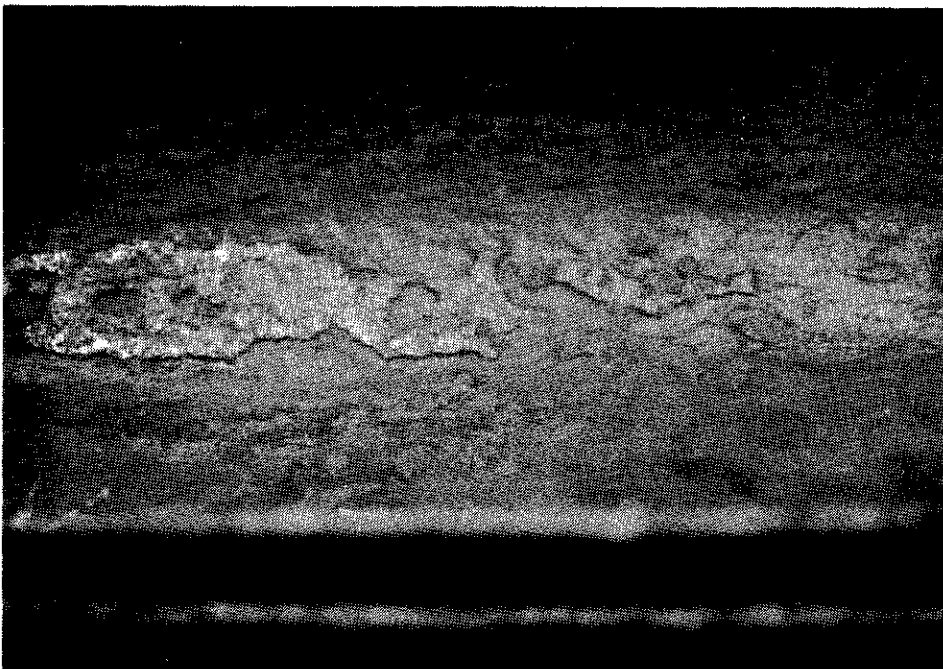


Photo 2

The types of equipment exposed to moving fluids and subject to erosion corrosion are piping systems (especially bends, elbows and and tees), valves, pumps, and heat exchanger tubes. In short when a rapid flowing fluid has to change direction rapidly, erosive effects should be considered likely. Metallurgically, hard surfacing such effected location with stellite or a similar material should be considered.

## CORROSION MECHANICS

There are only two basic mechanism which effect internal pipeline corrosion.

### I. Electrical Corrosion

### II. Chemical or Environmental Corrosion

#### Electrical Corrosion

Electrical Corrosion takes place when an applied potential is imposed on a piece of metal. This forces the metal to become anodic and metal ions escape from its surface. The rate at which this action occurs will depend on the potential impressed on the metal, and the rate at which the metal ions can escape from the surface. Thus transport equations can be set up and rates calculated under specific conditions. Under operational conditions a specific environment does not often reproduce itself. The amount of Hydrogen Sulfide, Oxygen, Water, Carbon Dioxide, Carbon Monoxide, Brine, or Acids (either Organic or Inorganic) may arrange themselves in various proportions which cause the final corrosion rate to be the same; however, on close examination, the transport rates are different, the surface charges are different, the materials in the environment are different, but the corrosion rate (the net effect) will be the same.

#### Chemical or Environmental Corrosion

This mechanism involves a chemical attack. Most often this not only involves one chemical reaction but a series of reactions. It is interesting to note that the "bad actors" may be generated or regenerated by bacteria, or the corrosion process itself. Bacteria by their action on organic compounds often release by-products which cause corrosion to take place. In the case of atomic hydrogen, it has been proved experimentally the rate at which one atom of hydrogen will combine with a second atom. However, at the surface of the metal, atomic hydrogen is generated. These atoms of hydrogen migrate through the metal and out the other side. When this happens, no harm is done. However, when atomic hydrogen finds a flaw in the metal, it may recombine with a second atom. Since the molecular hydrogen is too large to escape, it is trapped in the metal. When another atom of hydrogen passes into this intergranular area, it is trapped and with time a bubble is formed. This bubble exerts great pressure on the pipe wall. It can blow out, thus it reduces the wall

thickness of the pipe and may cause a rupture to occur. The presence of this reaction has caused NACE (National Association of Corrosion Engineers) to create a specification regarding the nickel content allow in pipe (1%) and a hardness specification (less than RC-22) when conditions for this reaction becoming probable occur. In the case above, it is when Hydrogen Sulfide is present.

As was indicated the driving force in chemical corrosion is the chemical reaction itself. As simple as this may seem, there are many factors which effect this. Surface concentrations of specific molecules which may block the transport characteristics of both the corrosion products as well as the unreacted corrosive elements. There are also chemicals which act as facilitators. Hydrogen Sulfide is such a material. Oxygen is another.

#### Hydrogen Sulfide

When either Iron Oxide (in any form) or Iron Chloride (in any form) is present, Hydrogen Sulfide's electrochemical potential insufficient to cause the reaction to result in an insoluble Iron Sulfide and the regeneration of the free atomic oxygen or atomic chlorine very near the metal surface. Atomic hydrogen is also present. This free radical mechanism would allow for the presence of free hydrogen near the metal surface. There has been no evidence presented that is conclusive which would exclude the hydrogen atom from moving in any direction. Therefore, it should have an equal probability of moving into the solution and thus recombining with some other atom or moving along the pipe wall which would also result in a recombination. Only when it moves into the pipe wall can the result be the problem discussed above. If the hydrogen recombines with a chloride free radical, then additional hydrochloric acid is regenerated to reattack the metal. Thus a cyclic process occurs.

#### Oxygen

Experiments have been performed, in which the positive effect of oxygen was shown. Starting with a concentration level in the low parts per billion, it has been found that the corrosion rate decreases with increasing concentration. As is well known, a corrosion rate minimum is reached. With the addition of oxygen in the parts per million level, the corrosion rate increased with additional oxygen being present. This can be explained by considering that the corrosion products are modified with the presence of dissolved oxygen. The diffusion rate or "activation energy" required to penetrate the surface layer is modified with the molecular formation present. The result would be a specific corrosion rate.

## CATALYST

One of the major catalytic molecules which cause an increase in the rate of corrosion while not taking place in either the initial or the final molecular structure is that of Cyanide. This material is most likely to have a effect at high pH levels. The exact mechanism is still somewhat uncertain; however, it can cause the corrosion rate in a solution above a pH of 9 to increase greatly. The exact degree of corrosion rate increase is not certain but it is real and is definitely measurable.

Organic cyanide has been found occurring naturally in petroleum. The source of this material may be inorganic salts or due to biological activity.

## CONCLUSION

Whatever the mechanism, whatever the prime materials which make up a corrosive environment, the attempt to learn more about this process and to prevent it from taking place is a challenging one. The technology for the study and detection of corrosion as well as prevention must continue to grow as does the exploration. While 38% of today's off-shore wells operate in water of 1,000 to 2000 feet (300 to 600 meters) and 3% in excess of 2,000 feet in depth, the capabilities already extend to 8,000 feet (2.4 km). It will involve new techniques for sea floor completion, for off-shore pipelines, and sub-sea production systems.

As the oil being produced decreases in quality, it is necessary for the technological expertise to protect these pipelines and process systems be expanded and more attention should be given to the mechanisms which are involved.

## Section IV

### REVIEW OF CORROSION KNOWLEDGE AND DESIGN CRITERIA IN ENGINEERING ONSHORE/OFFSHORE OIL PRODUCTION INDUSTRY

#### INTRODUCTION

It is the intent of the following section to present the level of knowledge and understanding of corrosion in engineering, as practiced by working engineers employed by engineering/consulting firms.

The following observations are based on a review of the available guidelines available in engineering/consulting companies and discussions with engineers active in the various disciplines, which comprise the engineering design staff.

It should be noted that specific questioning of in-house "Corrosion Experts or Specialist" and consultants has been omitted to present a realistic view of corrosion knowledge of the working engineer. Furthermore, the review and discussions in this section were restricted to personnel employed by companies providing engineering services specifically to the offshore and onshore oil production industry.

#### CORROSION AND ITS IMPACT

There exist in the world of engineering a general awareness of the "cost" of corrosion, and that such are expressible in terms of operational costs of the completed plant, facility or structure. There is no knowledge of accurate records indicating the "cost" of corrosion in terms of either operation, material or investment. None of the engineers nor their companies' engineering guides present an estimated cost. A review of old records, printed before 1966, indicated that on some oil field projects, cost of uncontrolled corrosion is conservatively estimated to be approximately 20 to 22% of the initial investment cost for the original system. An article by Dr. A.G. Ostroff of Mobil Corporation quotes similar estimates. No knowledge is available for estimates of "Cost of Corrosion" expressed in terms of indirect cost, such as repairs and labor. No knowledge of the annual cost of uncontrolled corrosion nationwide is available from our sources.

#### CORROSION CAUSES

When the causes of corrosion were reviewed, it was clear that the working engineer has a good knowledge of the cause of corrosion. This is elaborated by the companies' design guides, which refer to the NACE Standards and Practices - in particular to NACE Standard RP-01-75.

The following summarizes and categorizes the existing knowledge of the working professional engineer with regard to the causes of corrosion:

- o Definition of Corrosion
- o Causes of Corrosion
  - Water
  - Dissolved Oxygen
  - Carbon Dioxide
  - Hydrogen Sulfide
  - Dissolved Mineral Salts
  - Acidity of the Fluid
  - Velocity of Fluids in Pipelines
  - Temperature of the Fluid

#### Definition of Corrosion

The given definition of corrosion coincides with that established by NACE and is given as "The deterioration of a material, usually a metal, due to a chemical or electrochemical reaction with its environment."

A variant was given as "A destructive attack of a metal by a chemical or electrochemical reaction with its environment, usually occurring when produced oil field waters contact steel piping" or "Corrosion occurs when there is (1) an anode; (2) a cathode; (3) an electrolyte; and (4) an external connection."

The majority of the working professional engineers and design guides further define corrosion as occurring either on external or internal surfaces of equipment, pipelines, and structures.

#### Water Caused Corrosion

In general, it is acknowledged that the presence of water, in or on metal, will cause corrosion. The engineering professional recognizes that corrosion is not caused by the mere presence of water, but defines the cause of corrosion to be the presence of water containing dissolved corrosive substances such as sodium chloride, hydrogen sulfide, carbon dioxide. It is further recognized that temperature and velocity of the fluid either increase or decrease the corrosive qualities.

#### Dissolved Oxygen

It is almost by definition that the professional engineer will design to eliminate possibilities of having oxygen dissolved into a fluid, because of the corrosive potential. Dissolved oxygen is recognized as the most troublesome substance in the oil field designs.

The actual action of oxygen on metal surfaces is known, and many offshore designs go to great length to protect metal surfaces from oxygen/metal interaction by, for instance, oxygen removal. In salt water atmosphere, the design engineer, aware of its

corrosive qualities, will normally design around this problem by using protective coatings or noble materials. An example where such a practice occurs is the splash zone of offshore structures.

#### Carbon Dioxide

The second most troublesome substance known to the design engineer is carbon dioxide. Most of the design guides available to the professional engineer alerts him to the corrosive action of dissolved carbon dioxide in water - "sweet corrosion". Most engineering/consulting companies will recommend oxygen or carbon dioxide removal, but will rarely design to prevent this type of corrosion. Several equipment manufacturers, when faced with design of equipment processing dissolved carbon dioxide, will refer to specialists or design the equipment to allow for corrosion over the normal life of the equipment.

#### Hydrogen Sulfide

The presence of dissolved hydrogen sulfide and oxygen in production fluids is very corrosive and its action, that is the interaction of hydrogen sulfide/oxygen and metal, is well known to the consulting engineer. With the severest corrosive range being from 150 ppm to 400 ppm at 80° F, most designs are executed to eliminate this contaminant, if possible.

#### Dissolved Salts

That the presence of dissolved salts contributes to the corrosivity of the water is well accepted. Most design guides available advise the removal of the dissolved salts. The methodology for removal of dissolved salts is available in the industry. In contrast, the design parameters, to contend with dissolved salts, are known to few engineering/consulting companies dealing with storage of materials in natural salt domes or caverns.

#### Control of pH

The chemical nature of an electrolyte and its governing action is not new to professional engineers, and receives the proper attention during the design stages. Similarly, the temperature and velocity factors are normally included in the design parameters reviewed by design consultants. As a rule, design steps are taken to prevent this factor from exacerbating the problem.

#### Design Considerations

Several design considerations are utilized by the design or engineering companies which are presented hereafter. The majority of the design considerations covering corrosion apply principally to pipelines; i.e., external and internal corrosion. With regard to internal corrosion, all engineering companies have the following design considerations.

Several impurities are considered when designing pipeline distribution systems and these are:

- Bacteria
- Carbon Dioxide
- Chlorides
- Hydrogen Sulfide
- Organic Acids
- Oxygen
- Solids or Precipitates
- Sulfur Compounds
- Water

When any of the above impurities are present, normally the design team will:

1. Attempt to arrange with the owner or supplier of the commodity to have the impurities removed, or
2. Suggest to the owner or supplier of the commodity additional pretreatment to reduce the corrosive impact of the commodity on the pipeline distribution system.

Such suggested pretreatment covers:

- o Control of Flow Velocity
- o Avoidance of Abrupt Changes in Line Size
- o Dehydration and Dewpoint Control
- o Deaeration or Deoxygenation
- o Chemical Additives
- o Internal Coatings
- o Monitoring

#### Flow Velocity

The control of flow velocity consist of keeping the velocity inside the acceptable limits, such that the lower limit of the flow velocity keeps the impurities in suspension, while the upper limit is kept below velocities causing erosion, cavitation, or impingement.

#### Avoidance of Abrupt Line Size Changes

One of the methods employed by design engineers to assist in minimizing the possibilities of accumulation of corrosive impurities in the commodities, is the provision of smooth hydraulic transition from one size to another.

#### Dehydration and Dewpoint Control

The objective of this method is the removal of excess amounts of water in the commodity. If the reduction of the water content is not sufficient to control the corrosion, additional mitigating methods, such as pigging, are employed.

## Deaeration and Deoxygenation

Similar to dehydration and dewpoint control, this method removes or lowers substantially the oxygen content of the commodity to reduce the corrosive action of the fluid or the impurities.

## Chemical Additives

In addition to the above, some of the corrosion mitigating methods are the injection of chemicals, such as corrosion inhibitors, oxygen scavengers or bacteriacides. It should be noted that these methods require special mixing and injection facilities.

## Internal Coating

Where corrosion is anticipated, one of the methods selected may be the application of internal coating. This method has a disadvantage in that a distribution system is composed of pipes which are either welded or flanged together, causing a break in the continuity of the internal coating.

## Monitoring

Corrosion control, to be effective, should be monitored. Engineering companies' concern with corrosion control systems is limited to application methods, such as the efficiency of deoxygenation or rates of chemical injection. Other downstream monitoring methods are known but not applied due to the added design expense and the cost of monitoring equipment systems.

## CORROSION DETECTION AND MONITORING

A review of design guides and discussion with engineers employed by engineering/consulting companies reveals that the detection and monitoring of internal corrosion should take place. In contrast to the detection and monitoring of external corrosion, most engineers have difficulty in pin-pointing an efficient, economical way to accomplish the desired objective.

Most engineers will enumerate the following:

- o Usage of Visual Inspection
- o Usage of Corrosion Probes/Coupons
- o Sampling of Commodity and Analysis

## Visual Inspection

This is the most simplistic approach, but involves costly stoppages and interruption of the distribution system, and it is because of this that visual inspection is usually rejected immediately.

## Corrosion Probes and Coupons

The usage of corrosion probes and coupons is the most widely used method of internal corrosion detection. The placement of probes or coupons in onshore pipelines is fairly easily accomplished and monitored. For off-shore submerged lines, the placing of probes or coupons is restricted to accessible locations only. This limits the location to the starting and the termination points of the submerged lines; i.e., on the offshore structure or on land. No other practical locations for such devices are known.

Consequently, most submerged pipelines, subject to internal corrosion are either internally coated and/or designed (through increasing wall thickness) such that the effect of internal corrosion can be accommodated over the normal life of the lines.

## Sampling and Chemical Analysis

This type of monitoring is one of the NACE recommendations, which the working professional regards as purely theoretical, as it requires sampling and analysis of the product. Again in this instance, the onshore lines, because of their locale, are available for this type of monitoring. For the submerged lines, the sampling location is severely limited. In addition, the execution of the chemical analysis cannot easily be accomplished without a reasonable well equipped laboratory. Hence, this type of monitoring or detection of internal corrosion is seldom suggested or entertained.

## INTERNAL CORROSION CONTROL

The aforestated indicates that the problem of internal corrosion is recognized, and most of the engineering/consulting companies recommend an internal corrosion control method, consisting of a combination of pretreating, coating, or pretreating and pigging. Most engineering/consulting companies can recommend the pretreating, but will defer the design of coatings and pigging to subcontractors or consultants specializing therein.

## CONCLUSION

In general, the engineering/consulting companies personnel are well aware of the troublesome phenomena of internal corrosion, its causes, and to some extent the prevention thereof.

It is the consensus that internal corrosion, or for that matter all corrosion, is a costly matter. Not many, however, are able to express in concrete terms the cost of corrosion, and owners or operators are apparently not fully aware of the actual cost, assuming that overdesign in material will substantially offset the effects of corrosion.

As, at this time, no practical method exists to correctly evaluate the cost of corrosion, the elimination or prevention of internal corrosion receives minimal attention from the designer.

## Section V

### REMOTE MONITORING

#### PARAMETERS TO BE MONITORED

Previously we have discussed the corrosion mechanism currently considered present in off-shore pipelines. The factors which effect the corrosion rate are: Carbon Dioxide, Carbon Monoxide, Oxygen, Hydrogen Sulfide, Chlorides, Water, pH and Temperature. This first section will cover what instruments are capable of monitoring these parameters and the level of detection and sensitivity they exhibit.

##### 1. Carbon Dioxide and Carbon Monoxide

Carbon dioxide and Carbon Monoxide in the presence of water form a weak acid. From published reports, the level at which these acids can effect the corrosive process are in the low parts per million.

In order to analyze the quantity of these gases present, an in-line gas chromatograph or a in-line infrared analyzer is capable of detecting these gases.

In the case of the gas chromatograph, the Carbon Monoxide and Carbon Dioxide would have to first be converted catalytically to methane in order that they could be analyzed. The gas chromatograph has two types of detector systems. The most reliable is a thermal conductivity type. In order to get the sensitivity required, for our purpose, it will be necessary to use a flame detection system.

The gas chromatograph is considered by its manufactures to be a high maintenance device. Equipped with a flame detection unit, the reliability factor associated with this analytical system is even further reduced. It can not be recommended for remote locations.

A second detection system would be the in-line Infrared unit. While it is capable of measuring Carbon Monoxide and Carbon Dioxide directly, and is a low maintenance unit, it is doubtful that it is currently able to measure these two molecules at the concentrations necessary for corrosion control.

##### 2. Oxygen

The complete absence of oxygen in a system is known to accelerate the corrosion rate. Oxygen, in the parts per billion level, can inhibit the corrosion process as its concentration increases. However, when oxygen is found in a system in the parts per million level, with an increased concentration an increased corrosion rate is exhibited.

Oxygen can be measured in the parts per million range with the use of a glass membrane electrode. The problem which may occur if this system is used in the detection of oxygen in a oil and gas gathering system is (a) the electrode may be broken, and (b) an electrode would tend to be fouled by the contaminants present. In either case, the use of this device for remote measurements is not recommended.

### 3. Hydrogen Sulfide

Hydrogen sulfide is known to cause an acceleration of the corrosion process at concentrations in the low parts per million. At concentrations above 75 parts per million its direct effects on the corrosion rate are small. Above this concentration, it can effect the corrosion rate due to its ability to buffer a strong acid. Electronic probes which are capable of detecting hydrogen sulfide are not suitable for sustained use in a gas and oil pipeline.

### 4. Chlorides

Chlorides generally include both hydrochloric acid as well as the salt found in brine (salt water). Generally it produces a gross effect and can be assumed to be a key factor in pipeline corrosion. While this quantity can be monitored by the use of glass membrane electrodes, the same problems which would be exhibited measuring oxygen would be present, ie fouling and breakage.

### 5. Water

Production water is a major cause of internal pipeline corrosion. Under most production conditions, it must be assumed to be present and in a sufficient concentration to cause a problem. In an off-shore production environment, there is a high probability that it will be present in sufficient concentration that additional changes in the quantity present will have little effect on internal pipeline corrosion.

### 6. pH

The acidity or pH of the environment present in an off-shore pipeline system has a major effect on the corrosion rate. The technology is currently present which will allow the pH to be measured.

### 7. Temperature

The temperature which is present within a pipeline will have a major influence on the rate of corrosion. There are several types of probes which can measure temperature by the use of a thermocouple. Rugged accurate probes are present which can make this determination.

In addition to these factors which we have discussed, other physically measurable parameters are of interest. These include internal pressure of the pipeline, corrosion rate and some measure of the degree of protection which is present.

The goal of this project is to remotely obtain a corrosion profile of the system in a systematic means by remotely monitoring the sub-sea pipeline system. We also want this system to operate with a high degree of reliability.

What is necessary to obtain a corrosion profile of a sub-sea pipeline? During this study, it has been determined that a reasonably complete profile can be obtained by the use of two probes. One of which is capable of measuring Temperature and also Pressure. The second is capable of measuring the corrosion rate and providing us with some indication as to the degree of protection which is present.

As has been discussed above Temperature is important with regard to corrosion control....but why pressure? The pressure which is present in a pipeline is a major consideration with regard to the integrity of the pipeline. If the line is operated at low pressure even with a reduced wall thickness, the pipeline may be operated without danger of rupture. However, if a transient high pressure condition exist in the pipeline for only a short period of time the pipe may be weakened or may blow out. Also, if a pipe-line rupture takes place, it may be instructive to have a pressure profile of the pipe prior to the pipeline break.

The second probe will measure the corrosion rate. This reading will provide information not only on the general corrosive condition of the pipeline, but also the pitting corrosion condition as well. Since both pH (acidity) and corrosion measurements are essentially obtaining the same type of data, we have currently determined that pH measurements are not necessary at this time.

#### INSTRUMENTS TO BE USED

The probe tentatively chosen to determine temperature and pressure readings is an extremely rugged DIGITAL PRESSURE TRANSDUCER produced by the Panex Corporation. The Panex 1100A Pressure Transducer consist of a precision quartz/capacitance type pressure sensor complete with electronics to provide a dual frequency output. Independent temperature sensing of the pressure element is also included in the transducer. The two frequencies are then ratioed, corrected for temperature and linearized by the use of the Model 300 Computing Digital Indicator to generate a direct reading of pressure.

This device determines the pressure by an arrangement in which one capacitance element responds only to environmental effects, while the other element responds to environmental effects plus pressure. Each of these capacitance values are then converted to a frequency by a single capacitance-to-frequency converter. A

solid state switch, designed to contribute negligible error, is used to alternate the sensor capacitances to the converter input. The resultant frequency signals are then mathematically ratioed and processed by the output device (a model 300 CDI) to cancel environmental effects and converter errors. Additionally, the small remaining temperature coefficients are corrected by using the temperature information from the transducer. Because this device was designed and built to be used under oilfield condition it has the ruggedness as well as the sensitivity needed. Because of its construction, it should be capable of obtaining reliable data from a remote location over a long period of time with little or no maintenance.

The corrosion rate meter selected can be that manufactured by PETROLITE or one of a similar design. The corrosion meter will be of multi-electrode design which will be capable of determining the tafel curve and extract corrosion rate information from this data. Such devices are both rugged and capable of operating over an extended lifetime with little or no maintenance. The output from this device can be obtained in digital form.

In summary, the parameters which we will be monitoring are Temperature, Pressure, Corrosion Rate and an index which can be characterized as film thickness.

#### COLLECTION OF DATA

A preliminary determination has been made regarding the amount of data which is to be collected. Because of the system configuration, we feel that data points can be collected every two hours. If up to eight systems were to be monitored from each location, less than 32 bits of information would be collected over a 24 hour period. The rate of data collection could be modified once a data base is established. However, initially this collection rate is preferred. Because of the large amount of information involved, computerized analysis is necessary.

#### STORAGE OF REMOTE DATA - INSTRUMENT

The storage of the data collected at the site prior to transmission can be accomplished in two ways. First, the data could be stored in the Remote Advanced Status and Control Unit. However, this unit is not configured in such a way which would allow this to be accomplished easily. Also, by storing data at this location, the versatility of this unit would potentially be restricted. The second alternative is to place a storage device in the Panex Model 300 Computing Transducer Indicator. It is designed in such a manner that will allow it to intake additional digital data. It can be modified to provide the necessary storage configuration with minimum effort. It is also equipped with a high/low alarm limits which would allow the system to report an "exception" condition. The CTI is also equipped with a realtime clock for logging data as well as a backup power supply.

## STORAGE OF REMOTE DATA - DEVICE

The storage of information is dependent on insuring a high degree of reliability and the safety of the information collected. (Fail Safe storage). Various means of storage were considered. Included were cartridge type, cassette type, floppy disk, mini-floppy disk, hard disk, internal memory and EEPROMs. Because of the severe environmental condition which is experienced on an off-shore structure, and the degree of reliability and trouble-free maintenance which is required, it was determined that a mechanical device would probably prove unsatisfactory. The devices of choice were between a 64K memory chip with a back-up power supply or a 64K EEPROM. The 64K memory chip would be dependent on a back up battery to maintain the integrity of the stored data. The 64K EEPROM allows for the maintenance of data without power being present...no loss of data...and the data which it contains can be remotely erased upon reception of an electronic signal. The data stored in such a device is projected to be maintainable without power for a 20 year period. Therefore, for our purpose, it should be the device of choice.

## DATA TRANSMISSION DEVICE

The data transmission system selected was MOTOROLA's INTRAC 2000 System. It combines the advantages of providing both a secure, reliable method of data transmission with the flexibility of two way communication. Thus when a preset parameter which is being measured exceeds the limits set the remote device can inform the base station of the "exception condition". It also has the capability of allowing remedial action to be taken remotely to mitigate the effects of the more corrosive environment.

### Remote Unit

1. The remote device consist of a Motorola Advance Status and Control Unit. This unit combines the intake of digital information, its translation to a 32 bit bite, and the transmission of this data by radio.

2. The Advanced Status and Control Unit (ASCU) contains a security function. All messages transmitted and received are digitally coded to contain the unit's station address, alarm or function group, and alarm or control bits. For a word to be accepted, its code must pass all of the following checks:

- o Sync check at the start and end of each word
- o Bit count
- o Bose Chaudhuri check
- o Parity check
- o Bit width check

Therefore, the numerous code checks called "check forward" techniques guard against the receipt of false commands. Because of the high level of checking a message must pass before being accepted, neither speech nor unquenched noise can simulate messages. This also allows one to operate this system over secondary voice channels where permitted by FCC regulations.

3. The ASCU also incorporates a degree of redundancy to insure that the message gets through and is correctly received. To accomplish this the INTRAC ASCU unit sends each digital word several times during its initial two second transmission. Then if the unit does not receive an acknowledgement, the message is retransmitted up to seven times, or until an acknowledgement is received. This technique provides increased reception reliability over busy channels.

4. The ASCU provide an alarm function. Even though the system is silent, nonetheless it is constantly monitoring the inputs, but only initiate a transmission to the control base station when a change occurs which is outside the control parameters. This feature conserves valuable air time, while reporting information to the central station whenever it is needed. This feature allows the unit to report the "exception condition". When using this initiate feature, the unit automatically monitors the RF channel before transmitting to prevent information from becoming lost due to garbled transmission.

5. The ASCU has the ability to monitor up to eight (8) status inputs and can activate four (4) different relays. This not only allows one to monitor more than one array of units by the use of a single ASCU, but provides one the ability to remotely try to correct an "exception condition". Such rapid response can greatly facilitate ones ability to mitigate the effects of an increasingly corrosive environment inside the pipeline. It will also allow one to switch the unit from a periodic reading of a particular parameter to a continuous reading.

6. Because the ASCU must be located in remote locations, its ruggedness and reliability are of great importance. It is 100% solid state for improved efficiency and reliability. It incorporates high density CMOS technology for further enhanced equipment dependability. CMOS integrated circuits allow these units to be used in areas where temperatures fluctuate extensively. Input circuits are designed with built-in protection from electrical surges, which might occur on sensor circuits.

7. The ASCU is very versatile. It can be connected in such a manner that for situations where a large variety of information is needed, up to four ASCUs can share a single radio or with relay modifications multiple radios which can transmit at up to four different frequencies.

## Base Station

The base station of the INTRAC 2000 system is a radio receiver/transmitter which is capable of accommodating up to 512 remote units on a single RF channel without interference. The units can be different or the same depending on the configuration parameters. The systems large address capacity and flexibility allows one to design a system to meet specific requirements. It also has the versatility to be able to expand to accommodate additional usages.

## Computer Interface Unit

Motorola's INTRAC 2000 Computer Interface Unit (CIU) is a unique microprocessor based device that contains all the necessary logic associated with linking an INTRAC 2000 network to a customer-owned microprocessor, terminal or central processing unit (CPU). Basically, the Central Interface Unit encodes and decodes the INTRAC 2000 FSK messages and translates them to and from a simple ASCII RS232 serial format.

The CIU is designed to allow the user the means to develop programing suitable to his own needs via his own CPU. The CIU's protocol is deliberately simple and can be accommodated by a wide variety of CPU's. The user then has the ability to display, manipulate and store data, and develop responses that are consistent with his specific requirements.

## Central Control Computer

The central control computer will be a CROMEMCO System Three. This unit provides the versatility and an operating system which gives direct access to a single buffer file, while not compromising the security of the rest of the system. The software to be developed will most probability be written in the Fortran 77 language and be run on a Motorola 68000 chip which combines 16 bit characteristics and a 32 bit structure. This should give one a combination of great speed in data manipulation and maximum flexibility.

## Data Storage

The data will be stored on a optical disk. It will be formatted as to location, date, time, and type of data. The optical disk has two major features. First it holds up to 2.6 gigabites of information and second, it's laser write only system provides for data integrity of the data stored while allowing one complete access to the data. To put its storage capacity in perspective, it is roughly equivalent to the amount of text appearing in 15.4 years of daily newspapers. Yet despite this incredible filing capacity, any bit of information can be accessed via laser beam scanning in less than a quarter of a second. Once written, records are held permanently on disk for an expected file life of ten years or more, with an error rate so low that it approximates the industry standard for magnetic floppy disks.

This system will not only provide for data collection, and continuous monitoring of off-shore pipelines, but will also provide a data base for research. The problem which has been experienced with the build up of a large amount of data from diverse sources, is that the data becomes unmanageable for day-to-day use. However, with this type of system, not only will the information be obtained, but it can be put inmanageable form. Statistical useage and plots of this data will allow long range trends to be decernable which are now undetectable. It will also provide us with the ability to determine the corrosion, pressure and temperature history of a pipeline prior to a failure occurring.

#### Data Transmission Under Difficult Conditions

Even though Motorola's INTRAC 2000 system is capable of getting data through under conditions which are extremely difficult, conditions may exist which preclude digital transmission over this system. In such a case, the INTRAC 2000 system can be linked with the Comspec 9600C. This device should not be necessary in most cases, but it provides a invaluable link should the RF transmissions in a particular area deteriorate to a point to where data transmission is not possible. This unit is compatable with DDD, microwave, satellite, UHF/VHF radio circuits. The advantage of having this device available is that it provides interactive communication between pairs of these devices.

#### DATA COLLECTION PROTOCOL

##### Normal Condition

Under normal conditions, the computer will activate the appropriate base station to call up a specific remote Advanced Status and Control Unit (ASCU). This will occur at a time when the radio transmissions are low, most probably between 0300 and 0500 in the early morning. This time was chosen because the automatic data collection will be software controlled and the computer will respond at any pre-selected time. During this inquiry all data dumps will be made and storage devices will be cleared once the data is confirmed. This polling of the ASCU will be completed prior to the following work-day. Thus the information obtained can be monitored by a corrosion specialist to determine if there is additional information needed or if there is a potential problem developing at a particular location.

##### The "Exception Condition"

Under the exception condition the remote unit sends a signal to the central CPU indicating that a problem is occurring. This call-up will occur when predetermine parameters are exceeded. When this happens the monitoring equipment can be placed on-line with the use of the ASCU's switching capability and a determination will be made as to the appropriate action. The

pipeline operators will be notified and advised as to the readings being obtained. The options available will be discussed and any action must be authorized by the pipeline operators.

The information which may be obtained during an upset condition will be very helpful in determining what is happening and may be correlated with prior information and later information to provide help in determining what happened if a pipeline failure occurs at a later date.

## Section VI

### CONCLUSIONS:

The general objective of this research is to provide a means of remotely monitoring internal pipeline corrosion taking place in off-shore pipeline systems so that corrective action can be taken.

As Phase I Specific Objectives we needed answers to the following questions:

1. Are Radio Modems available which are able to transmit stored corrosion data from remote off shore platforms?
2. If remote radio modems are commercially unavailable, which could be modified to transmit corrosion data from remote, off-shore platforms; what would be the electronic configuration necessary to accomplish this task?
3. What means of storing corrosion data could be used so that the remote transmission of the data is feasible?
4. Is it feasible to interconnect corrosion devices that can monitor corrosion data so that remote acquisition can be made possible?

It was determined, during the course of this investigation, there are several possible approaches which can be used to remotely obtain corrosion data from off-shore platforms. In 1978, Motorola introduced the INTRAC system; however, only in 1983 was this system sufficiently upgraded to allow for its use in this application. Also, only in the 4th Quarter of 1983, was a system brought to market which would allow digital transmissions under severely degraded conditions.

Also, during this research, it was ascertained that other operational data may be needed to determine a profile of the corrosive environment. It was determined that Temperature and Pressure were additional parameters which should be also obtained by remote monitoring. The means of determining these parameters, storing the information and transmitting it were determined.

Since the means to acquire remote data from off-shore platforms was commercially available, it was unnecessary to undertake a modification of existing units.

A survey was undertaken to determine the best way to store data under severe environmental conditions such as those which exist of off-shore platforms. Particular attention was given to the reliability, security and ruggedness of any device used. It was determined that a 64K memory chip with a battery back up unit was

the best solution; however, with the recent introduction of the EEPROM 64K chip, this device is preferred. Its choice is due to the ability to store information, obtain this information and remotely clear its memory for additional data. Should a power failure occur, the data currently in its memory would not be destroyed even in the event that battery power was also lost. Its major drawback is the lack of sufficient quantities currently in the market. If this system were to be build today, in large quantity this would represent a problem; however, since the need for these devices is in the future, we have been assured that there will be a sufficient quantity available in the reasonably near future.

During this research, it has been determined that two methods may be used to interconnect the corrosion monitoring device and the Pressure & Temperature unit to a remote transmission device. This is through the use of a RS232 connection or through the use of a IEEE-488 connection. Since each of these methods has advantages and disadvantages, it will necessarily await Phase II before the final determination can be made as to the best method for this particular application.

Phase I of the SBIR Program is basically a feasibility study to determine if the project can be accomplished. The Phase I objectives have been met...on time...on schedule. Phase II will consist of building a prototype of this remote data acquisition system which will allow us to obtain basic data on the status of off-shore pipelines. Our greatest challenge will be to devise a system configuration which is software controlled. That is the need of personal attention in the data acquisition, verification, indexing or logging of the data will all be under software control. The initial screening of this data and statistical parameters will also be accomplished to assure the person accessing the data that it is from the same population. Thus, if there is occurring a significant change in the environment in the off-shore pipeline, the software should be able to determine the change. This might not be as evident to an observer, because of random "noise" which is generally present in raw data. However, because of statistical evaluation by the software, any real change may be more evident.

The writing of a set of software packages which will allow hands-off operation of the system will be a challenge. Part of this will require a program for:

- (a) polling or calling up the systems to obtain the data,
- (b) obtain proper verifications to determine that the channel is clear,
- (c) checking the system to insure that it is working properly,
- (d) checking the data obtained from a specific remote site to insure that it is "new data" is valid,
- (e) log the new data into the buffer,

- (f) update the data base,
- (g) perform statistical analysis on the new data,
- (h) compare the new data to the data previously obtained from that location, and
- (i) prepare an update for the corrosion engineer so that he can review the status of each set of data points and how they fit with the set-up at that location.

With the advent of the system as now determined, three major function would be accomplished:

- (1) day to day control of the corrosion in sub-sea pipelines,
- (2) the generation of a history of the system being monitored, and
- (3) the generation of a data base which would allow corrosion specialist to do research work in an area in which very little hard data exist.

This would allow those who have the responsibility of maintaining the system to ACT to control excessive corrosion rates and not have to REACT after a pipeline rupture has taken place. Thus the environment of our coastal waters will suffer less pollution than would have otherwise taken place. This is not to say that even with the best corrosion control, pipelines will not experience problems. This condition may be present due to ships dragging their anchors across pipelines thus scoring and weakening them. Thus a rupture could take place which is not corrosion related. However with a proper choice of alarm parameters, the presence of a pipeline rupture should be manifest to the monitoring units and immediate recognition of an "exception condition" taking place would be evident. Thus appropriate action could be taken to minimize its effects. It would also establish a "history" of the conditions which took place prior to rupture. Such a profile will enable the computer to scan existing systems and should a system undergo a similar set of circumstances, then the detrimental effects could be minimized.

## Section VII

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